State of California **Public Utilities Commission**
San Francisco

M E M O R A N D U M

Date	**:**	**September 21, 2005**
To	**:**	**David H. Meyer, Acting Deputy Director, Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy** **Economic.Dispatch@hd.doe.gov**
From	**:**	**Bishu Chatterjee** **Energy Division, California Public Utilities Commission** **Regina DeAngelis** **Legal Division, California Public Utilities Commission**
Subject	**:**	**Study of non-utility participation in economic dispatch pursuant to Section 1234 of the Energy Policy Act of 2005**

The staff of the California Public Utilities Commission ("CPUC") welcomes the opportunity to respond to the September 1, 2005 letter from the U.S. Department of Energy ("DOE") seeking information on non-utility participation in economic dispatch pursuant to Section 1234 of the Energy Policy Act of 2005. The information below responds to the questions attached to the September 1, 2005 letter. Should the DOE require additional information, please contact Mr. Bishu Chatterjee at (415) 703-1247. This information has been compiled solely by the Energy Division of the CPUC and the positions taken here have not been formally approved by the CPUC.

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1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

In California, economic dispatch procedures are employed by the California Independent System Operation ("ISO"). Under these economic dispatch procedures, the California ISO seeks to optimize its entire grid generation by minimizing the total cost to the ISO's system. Accordingly, the California ISO dispatches the generation units that appear economically most efficient while simultaneously considering the transmission capacity limits of the grid. The California ISO has 55,183 megawatts of power plant capacity, 15,000 market transactions hourly, 25,526 circuit miles of transmission lines, 30 million people served, $2.7 billion annual billings and 230 billion kilowatt-hours of power delivered annually[1].

2) Is the Act's definition of economic dispatch appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

Section 1234 of the Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities."

The California ISO may follow the above definition in principle when it triggers its economic dispatch process. However, the primary driver of its optimization is system cost minimization, not necessarily a particular generation unit's energy production at the lowest cost. Similarly, the total system cost is minimized based on various generation units' offered bid prices and not on the actual marginal cost of a generation unit's operations. Currently, the California ISO applies economic dispatch principles to the real time imbalance energy market only. The California ISO intends to expand its economic dispatch process to day-ahead and hour-ahead markets in February 2007. At the same time, the California ISO intends to institute locational marginal energy pricing for the entire control area.

Ideally, for economic dispatch to be truly efficient it should cover as large an area possible. The California ISO does not cover all the areas of the California grid, such as the control areas owned by municipalities.

In addition, the California ISO economic dispatch model currently does not optimize over all the environmental constraints such as emission limits due to its software limitations.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please

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[1] California ISO 2004 Annual Report.

indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

The California ISO's economic dispatch process does not differentiate between units based on ownership (i.e., utility versus non- utility generation). However, under the California ISO's current imbalance energy market (a day-ahead market will not exist until February 2007), some of the Qualified Facilities ("QFs") are not subject to the Must Offer Obligation and hence are not considered under the economic dispatch procedures. Furthermore, while the CPUC does not have any specific analysis or position on this topic, there is a growing consensus at the California ISO stakeholder meetings that the ISO should be able to recognize the individual ability of each plant's energy generation based on a generation unit's production characteristics, such as combined cycle thermal plant, hydro, or wind generation.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

The above situation does not apply to California since under the California ISO the economic dispatch process does not distinguish between utility and non-utility generation. In other states, if an ISO-type grid operator does not exist, the possibility exists that the investor-owned utility will give preferential treatment to its own generation to the detriment of non-utility generation. In such a situation, it is possible that preferential treatment will interfere with the application of economic dispatch.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

This question does not apply to California. Please see the response to Question 4, above.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Currently, the California ISO is undergoing its Market Redesign and Technology Upgrade ("MRTU") program that will introduce economic dispatch based on locational marginal pricing as well as broaden the market to include day-ahead and hour-ahead. Under the MRTU, California will experience positive grid reliability. The economic dispatch model is applied to spot energy markets (day-ahead, hour-ahead, and real-time). Along with economic dispatch, California is also looking at non-spot markets, such as long-term bilateral contracts and capacity market and transmission upgrade projects to assure adequate generation.